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Life Cycle Assessment of GHG Emissions from LNG and Coal Fired Generation Scenarios: Assumptions and Results

Prepared for:

Center for Liquefied Natural Gas (CLNG)

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PACE OVERVIEW

The Center for Liquefied Natural Gas (CLNG) retained Pace to perform an independent assessment of the greenhouse gas emissions resulting from the life cycle process of generation using LNG fuel supply and competing coal fired generation options. This document presents the results of this independent assessment and the major assumptions underlying this analysis.

Pace is an independent energy and carbon consulting and management firm with clients and engagements across the globe in over 40 countries and six continents. Headquartered outside Washington, D.C. with offices in Houston, New York, Columbia, San Diego, Sacramento, London and Moscow, Pace provides expertise in the following areas: energy asset and infrastructure development and management, risk management, global energy market forecasting and transaction due diligence, M&A and asset disposition, carbon & environmental market advisory and management and related technical services. Since 1979, Pace has provided innovative services to support the execution of a full spectrum of business strategies and complex energy transactions. Throughout our history, Pace has developed integrated solutions that address both environmental and economic considerations by applying creativity, deep subject matter knowledge and integrity to every engagement.

Pace is well qualified to perform this life cycle greenhouse gas emissions analysis due to its depth and breadth of experience across the energy sector including fuel supply, energy technology and engineering, carbon management and power generation. Pace assists clients through all stages of energy production from fuel supply at the wellhead through consumption at the burner tip. Notably, Pace is or has been engaged in permitting, financing, and / or development efforts for more than five LNG facilities in the U.S. alone. In addition, Pace has a dedicated Carbon Management practice comprised of top professionals experienced in the formation of carbon markets, global regulatory drivers and the cutting edge standards and practices for quantifying GHG footprints and lifecycle carbon intensity. Pace's carbon services are highly regarded in the industry and Pace is actively deploying cutting edge carbon management practices and management systems to prepare companies for future carbon constraints. Pace has provided comparative greenhouse gas life cycle emission assessments on behalf of proposed LNG terminals and other generation options.

INTRODUCTION & KEY FINDINGS

The Center for Liquefied Natural Gas (CLNG) commissioned a multi-scenario life cycle assessment (LCA) of carbon (or greenhouse gas – GHG) emissions attributable to several domestic generation options including natural gas-fired power generation supplied by imported liquefied natural gas (LNG) and conventional and advanced coal generation alternatives. The following four technology cases are included in the multi-scenario carbon LCA prepared for CLNG:

1. U.S. notional LNG supply and transportation system and end-use combustion using a modern natural gas fired combined cycle (NGCC) power plant;

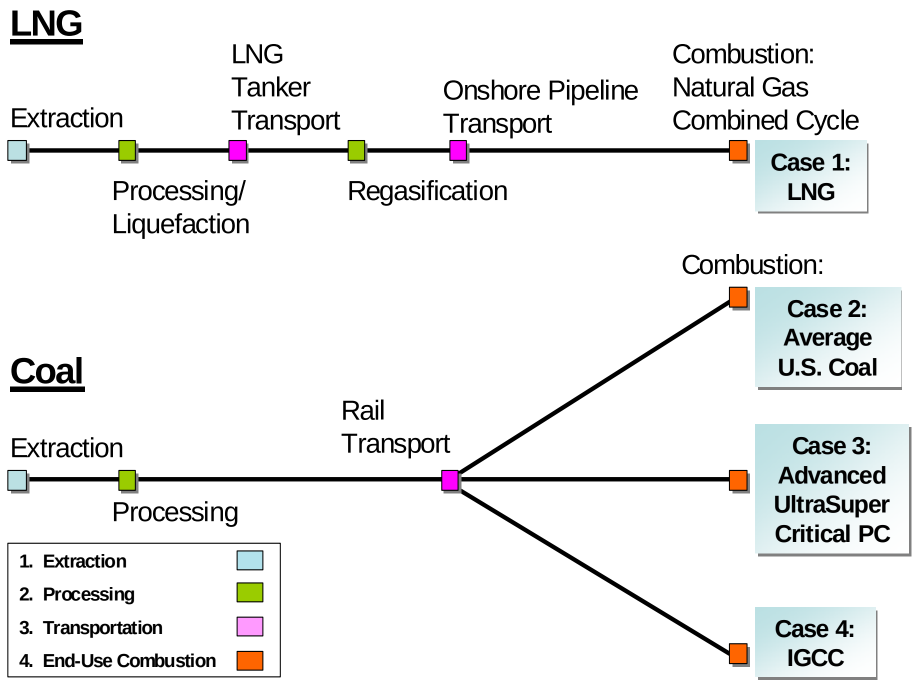
2. Coal supply, transportation, and end use combustion representative of the current U.S. coal technology mix;

3. Representative U.S. coal supply and transportation and end-use combustion using advanced ultra supercritical coal fired (SCPC) power plant (that is characterized by high efficiency);

4. Representative U.S. coal supply and transportation and end-use combustion using integrated gasification combined cycle (IGCC) coal fired power plant.

Pace calculated the aggregate life cycle carbon emissions for all scenarios. All assumptions, calculations and interpretation of the results of the LCA will be presented in this report. Exhibit 1 presents the generation scenarios assessed.

Exhibit 1: LCA Scenario Diagrams



Source: Pace

The intent of this analysis was to provide a transparent, consistent, and equitable "apples to apples" comparison of the GHG emissions attributable to generation in the U.S. based on assumptions that reflect the typical, average, or most common practices, processes, equipment, and geographical considerations associated with the selected scenarios.[1] The LCA quantifies the amount of three of the six main Kyoto GHGs (carbon dioxide – CO_2, methane – CH_4 and nitrous oxide – N_2O) emissions associated with electric energy consumption, fuel combustion and fugitive losses (including CO_2 and CH_4). The other three main Kyoto GHGs (sulfur hexafluoride – SF_6, hydrofluorocarbons - HFCs, and perfluorocarbons - PFCs) were excluded from the analysis as emissions of these GHGs were estimated to be negligible in the processes considered.

DEFINITION OF BOUNDARY CONDITIONS

This LCA quantified and compared all applicable GHG emissions associated with the life cycle of power produced with imported LNG and coal using a variety of different combustion technologies. The analysis was carried out under the following assumptions:

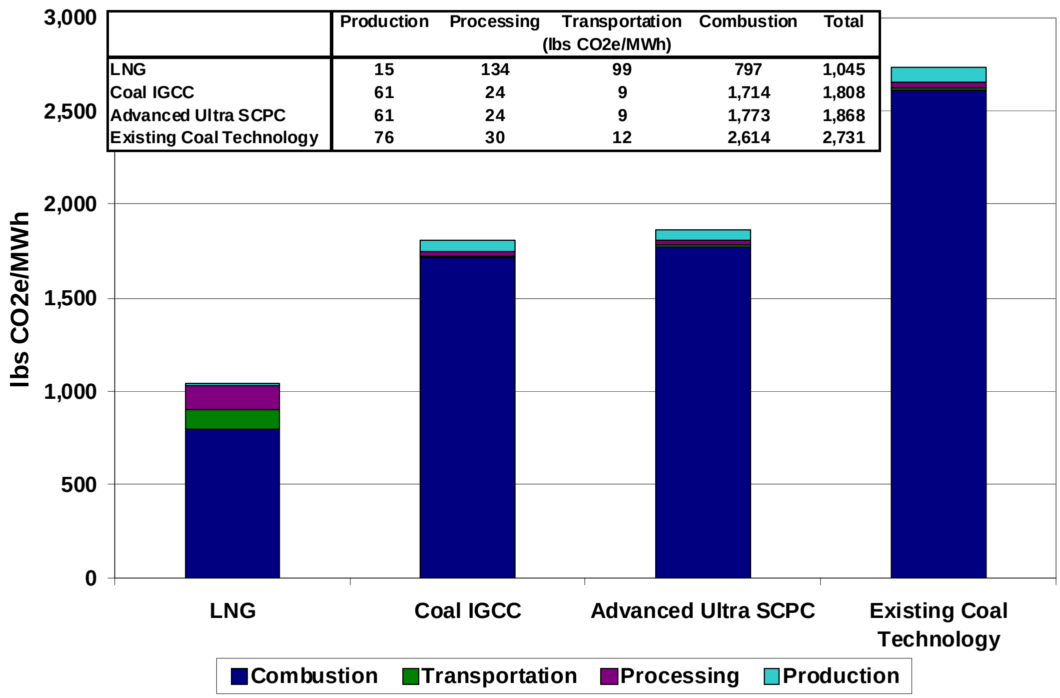
[1] While the results of the analyses are reported in a single value for each scenario, it should be noted that this report will not be representative of any facility specific supply chains and that significant variation exists within actual supply chains. This analysis was constrained by the relative accuracy of publicly available data sources for characterizing the notional U.S. generation supply chain. These sources of uncertainty and variation make it impractical to draw strong conclusions from small differences in life-cycle emissions. Instead, the reported results are intended to demonstrate the relative GHG impact of various fuel alternatives and technology options.

- Production, processing, and transportation of fuels representative of current U.S. energy production streams.
- With the exception of the current coal technology scenario, combustion technologies represent advanced and efficient generation options expected for new builds.
- The LCA examined the entire life cycle of the fuels including extraction (of fuel from already developed wells and mines), processing, transportation, and combustion.
- The LCA boundary included only process and operation-related emissions and did not include emissions from the construction or decommissioning of infrastructure, such as construction of power plants, trains, ships, etc.
- The LCA only included emissions from the operation of infrastructure directly attributable to the fuel combusted in the end-use power plant. Results are presented in terms of pounds of carbon dioxide equivalents per megawatt hour of generation (lbCO2e/MWh).

SUMMARY OF RESULTS

Exhibit 2 presents total GHG emissions for each stage of the life cycle for all scenarios. For all of the coal cases, production and combustion emissions were greater than the LNG case. However, the processing and transportation segment emissions were greater in the LNG case. Existing coal technologies emitted more GHG emissions than advanced coal technologies --- IGCC and advanced ultra SCPC.

Exhibit 2: Summary of LCA Results



	Production	Processing	Transportation (lbs CO2e/MWh)	Combustion	Total
LNG	15	134	99	797	1,045
Coal IGCC	61	24	9	1,714	1,808
Advanced Ultra SCPC	61	24	9	1,773	1,868
Existing Coal Technology	76	30	12	2,614	2,731

Source: Pace

LCA ASSUMPTIONS

Data and assumptions for this analysis were obtained from publicly available sources. Estimations and judgments, where needed, were made by industry experts from Pace and CLNG membership base. A complete list of references follows this document.

LNG COMBUSTION USING MODERN NGCC POWER PLANT

Production (Offshore, Includes Field Processing)

The production segment assumed offshore production as well as field processing. Pace's LNG production assumptions were primarily based on *Tamura et. al* which surveyed gas fields in LNG exporting countries: Indonesia, Malaysia, Brunei, Australia, and Alaska. A dry gas proportion of product mix of 0.89 based on data from the API Compendium was assumed.

Emissions in this segment included:

- CO_2 from natural gas combustion in gas turbines driving compressors for extraction;
- CO_2 from purge gas burned and discharged in the flare stack;
- Vented CH_4 produced during dehydration; and
- Fugitive CH_4 from compressors were deemed insignificant and were not quantified.

Pace referred to Climate Mitigation Services (CMS) and Tamura et al. in determining fuel consumption (through combustion) rates in offshore production. Pace found Tamura's emissions rate of 2.13 lbs CO2e/MMBtu produced to be consistent with other industry estimates and consequently adopted it for this analysis. Pace further proportionately adjusted the fuel consumption estimate of CMS to reflect Tamura's emissions rate.

Segment CO2e Emissions	1.889	lbs CO2e/MMBtu Produced
	12.69	lbs CO2e/MWh
	15.13	Adj. lbs CO2e/MWh

Processing / Liquefaction Plant

Emissions and fuel consumption rates for processing and liquefaction segments from several sources were reviewed for this LCA. Actual emissions and fuel consumption rates will vary depending on a number of factors including technology vintage, local environmental conditions, feed gas composition, and facility capacity and utilization. For this analysis, data from the Tamura study was selected, which was based on a survey of several international LNG suppliers. The results from the Tamura study were found to be consistent with figures from several facilities cited in the Pluto study. The data takes into account CO_2 emissions from fuel consumption, flare combustion, vented CH_4, and release of raw CO_2 gas. Pace assumed 8.8% of liquefied volume is combusted during this phase based on data from Tamura. It should be noted that other studies, including studies of Atlantic LNG Train 4, calculated a higher combustion percentage values. Pace found that using an 11.57% value consistent with other studies, would change the total LCA emissions by a negligible amount (less than 0.4%). Therefore, Pace used the Tamura combustion percentage to maintain a consistency of sources throughout the segment.

Segment CO2e Emissions	16.167	lbs CO2e/MMBtu Liquefied
	108.62	lbs CO2e/MWh
	127.79	Adj. lbs CO2e/MWh

Transportation via LNG Tanker

Several studies were evaluated to determine the emissions during the transportation segment. The LCA used the following assumptions and calculations:

- Tanker size of 138,000 cubic meters;
- Roundtrip transport distance to the U.S. (weighted average) of 7,369 nautical miles;
- Average tanker speed rated at 19.5 knots;
- Transport emission rate of 2,670 lbs CO2e/nm;
- Cargo combustion rate of 19.87 MMBtu/nm; and
- Natural gas fuel consumption at 5% of delivered volume.

Segment CO2e Emissions	6.409	lbs CO2e/MMBtu Delivered LNG
	43.07	lbs CO2e/MWh
	46.57	Adj. lbs CO2e/MWh

Regasification Facility

Data available for GHG emissions from the regasification segment of the LNG lifecycle vary greatly. Some studies suggest that the cryogenic energy of LNG can be used to create power, provide air separation services, and to conduct other useful services that can potentially offset the net emissions of the LNG lifecycle. However, this LCA used conservative data to estimate emissions during this segment. The Yang and Huang study suggested that this segment consumes 1.5% of natural gas send-out. The LCA assumed emissions of 0.85 pounds of CO2e based on the Tamura study and then assumed that the regasification facilities necessitate the use of one crew (security) boat operating during the entire docking and unloading process along with two tug boats.

Tug:

Segment CO2e Emissions	0.155	lbs CO2e/MMBtu Delivered LNG
	1.04	lbs CO2e/MWh
	1.07	Adj. lbs CO2e/MWh

Plant:

Segment CO2e Emissions	0.850	lbs CO2e/MMBtu Sent Out
	5.71	lbs CO2e/MWh
	5.89	Adj. lbs CO2e/MWh

Pipeline to Power Plant

Emissions from pipeline transport are very segment specific, varying with pipeline infrastructure, compression energy source, and segment distance. In order to most accurately define the related emissions for an average U.S. pipeline haul, the LCA assumed pipeline fuel consumption and both combustion and non-combustion CO2e emissions based on EIA natural gas consumption data and data from the U.S. GHG Inventory released by EPA in 2008. This data yielded an average retention rate of 1.7% (per unit volume). This fell within the range of retention rates for major U.S. interstate pipeline tariffs, which Pace found to be between 0.5% and 4%. For LNG, this U.S. average rate may be considered conservative for terminals located within close proximity to the point of natural gas delivery.

Segment CO2e Emissions	7.496	lbs CO2e/MMBtu
	50.37	lbs CO2e/MWh
	51.12	Adj. lbs CO2e/MWh

Power Plant

For this analysis, the LCA used assumptions from the U.S. Department of Energy's National Energy Technology Laboratory (NETL)'s Exhibit ES-2, Case 13.[2] The study assumes that:

- The NGCC plant has a capacity of 560 MW;
- The heat rate is 6,719 Btu/kWh; and
- The CO2e emissions factor is 797 lbs CO2e/MWh.

Segment CO2e Emissions	Plant Emissions Factor	797	lbs CO2e/MWh

Total CO2e Emissions	Total lbs CO2e/MWh	1,045	lbs CO2e/MWh

U.S. COAL PRE-COMBUSTION LIFE CYCLE

MINING

Pace used published data to estimate the emissions attributable to coal production and transported an "average" distance to a coal-fired generation unit in the U.S. The details underlying the U.S. based coal generation scenarios in the LCA are as follows:

- EIA data indicates about 69% of coal produced in the U.S. is produced through surface mining and 31% is produced through underground mining.[3] Pace used these statistics to produce a weighted average estimate of emissions from mining coal in the U.S.

- To estimate emissions from underground and surface mining, Pace uses assumptions from a study prepared for the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE).

[2] Cost and Performance Baseline for Fossil Energy Plants, NETL 2007
[3] EIA Production Data, 2007

- Pace estimated fugitive methane emissions from coal mining using EIA coal production data and data from the U.S. GHG Inventory data released by the EPA in 2008. Captured methane is not included as a (fugitive) emission.

- Pace used emissions factors published by The Climate Registry to estimate emissions from diesel combustion in locomotive transportation and mining equipment.

- Pace used EPA eGrid national average emissions factors for estimating a weighted average of GHG emissions generated by the existing U.S. coal fleet. Pace used global warming potentials for methane and nitrous oxide from IPCC's Second Assessment report where applicable.

Underground Mining

For the underground mining component of the analysis, Pace used assumptions from EERE's hypothetical Eastern Underground Coal Mine.[4] This study assumed:

- A room and pillar coal mine operating over a 20-year lifetime with a 20 million-ton output at the end of its life;
- Mine runs 301 days per year with two 9 hour shifts per day, giving it a daily production rate of 3,322 tons per day;
- Deposit characteristics are a bedded deposit with an average dip of 18 degrees;
- Average maximum horizontal is 2,900 feet and a minimum of 20 feet;
- Average maximum vertical is 5.9 feet with a vertical distance to the surface of 1000 feet.

Electrical equipment at this hypothetical site includes:

- 11 main fans;
- 25 LHDs;
- 13 drills;
- Two boon jumbos;
- Two continuous mining machines;
- One crusher;
- One conveyor;
- Two water pumps;
- One diamond drill.

Diesel equipment at this hypothetical includes:

- 31 service trucks;
- Six ANFO loaders;
- One roof bolter.

Segment CO2e Emissions (Underground)	206.6	lbs CO2e/Ton

[4] Energy and Environmental Profile of the U.S. Mining Industry, EERE 2002

Surface Mining

For the surface mining component of the analysis, Pace used assumptions from EERE's hypothetical Western Surface Mine.[5] This study assumed:

- Coal mine operation over a 20-year lifetime with a 200 million-ton output at the end of its life;
- Mine runs 360 days per year with two shifts per day of 10 hours which gives it a daily production rate of 27,778 tons per day and a daily waste production of 138,890 tons per day;
- Distance the ore must travel is 1,000 feet at a gradient of 8 percent and the distance the waste must travel is 70 feet with a gradient of 8 percent.

Electrical equipment at this hypothetical site included:

- Four cable shovels;
- Two rotary drills.

Diesel equipment at this hypothetical included:

- 11 rear dump trucks;
- Seven bulldozers;
- 20 pick-up trucks;
- One water tanker;
- Two pumps;
- Two service trucks;
- Two bulk trucks;
- One grader.

Segment CO2e Emissions (Surface)	106.3	lbs CO2e/Ton

Segment CO2e Emissions (Weighted Ave.)	137.2	lbs CO2e/Ton
	7.0	lbs CO2e/MMBtu
	75.9	lbs CO2e/MWh

COAL PREPARATION

For the coal preparation component of the analysis, Pace used assumptions for the beneficiation process from EERE's hypothetical Eastern Mine.[6] Over 98% of the energy in this case is used by the electric grinding mill. Other sources of emissions are an electric centrifuge, floatation machine, screens, and a magnetic separator.

Fugitive methane emissions associated with coal preparation were estimated by Pace using EPA's 2008 GHG Inventory data and data from EIA on US coal production.

[5] Energy and Environmental Profile of the U.S. Mining Industry, EERE 2002
[6] Energy and Environmental Profile of the U.S. Mining Industry, EERE 2002

Segment CO2e Emissions	54.1	lbs CO2e/Ton
	2.8	lbs CO2e/MMBtu
	29.9	lbs CO2e/MWh

RAIL TRANSPORTATION

For the transportation component of this analysis, Pace estimated that:

- The average rail trip for a roundtrip delivery of coal is 1,480 miles;
- The average delivery is 12,200 tons of coal per trip;
- The average consumption of diesel fuel during delivery by the trail is 0.13 gallons per mile;
- The rail train has 100 cars and 2 locomotives.

Segment CO2e Emissions	21.0	lbs CO2e/Ton
	1.1	lbs CO2e/MMBtu
	11.6	lbs CO2e/MWh

COAL POWER GENERATION TECHNOLOGIES

AVERAGE U.S. COAL-FIRED POWER PLANT

For this analysis, Pace preliminarily estimated that:

- The average capacity of existing coal plants currently operating in the U.S. is 455 MW;
- The weighted average heat rate is 10,824 Btu/kWh;
- The weighted average CO_2e emissions factor is 2,614 lbs CO2e/MWh.

Segment CO2e Emissions	2,614	lbs CO2e/MWh

Total CO2e Emissions	2,731.4	lbs CO2e/MWh

ADVANCED ULTRA SUPERCRITICAL COAL FIRED POWER PLANT

For this analysis, Pace used assumptions from the U.S. Department of Energy's National Energy Technology Laboratory (NETL)'s Exhibit ES-2, Case 11.[7] The study assumed that:

- The advanced ultra supercritical coal fired plant has a capacity of 550 MW;
- The heat rate is 8,721 Btu/kWh;
- The CO_2e emissions factor is 1,773 lbs CO_2e/MWh.

Segment CO2e Emissions	1,773	lbs CO2e/MWh

Total CO2e Emissions	1,867.6	lbs CO2e/MWh

[7] Cost and Performance Baseline for Fossil Energy Plants, NETL 2007

INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) COAL FIRED POWER PLANT

For this analysis, Pace used assumptions from NETL's Exhibit ES-2, Cases 1, 3, and 5, averaged.[8] The study assumed that:

- The IGCC plant has a capacity of 633 MW;
- The heat rate is 8,636 Btu/kWh;
- The CO_2e emissions factor is 1,714 lbs CO_2e/MWh.

Segment CO2e Emissions	1,714	lbs CO2e/MWh

Total CO2e Emissions	1,808	lbs CO2e/MWh

[8] Cost and Performance Baseline for Fossil Energy Plants, NETL 2007

RESULTS AND INTERPRETATION

BASE CASE RESULTS

Exhibit 3 presents a summary of the base case LCA by process for each scenario.

Exhibit 3: Results of Base Case LCA by Process

Scenario	Production	Processing	Transportation	Combustion	Total
(lbs CO2e/MWh)					
LNG	15	134	99	797	1,045
Current U.S. Coal Technology Mix	76	30	12	2,614	2,731
Advanced Ultra Supercritical	61	24	9	1,773	1,868
IGCC	61	24	9	1,714	1,808

Source: Pace

INTERPRETATION OF LCA BASE CASE RESULTS

To date the U.S. has declined to implement regulated carbon constraints. Federal climate change bills have been proposed sporadically in the U.S. Congress since the late 1990's and have gained little traction until very recently. Over the past year or so, pressures for the U.S. to take mandatory action to address climate change have been mounting. With federal GHG regulation on the horizon, it is important to consider the full realm of carbon implications from large scale generation options in planning energy developments to support a low carbon economy.

Benefits of LNG Supply in the U.S.

- The increases in current domestic natural gas reserves are dependent upon greater exploitation of unconventional reservoirs and difficult to drill areas. These types of domestic sources of natural gas need to be supported by sources of natural gas from other locations, especially under a carbon constrained economy where natural gas is the low carbon alternative to oil and coal. The natural gas reserve to production ratio in North America is around 10, while that of other prominent producing regions is much greater, with the Middle East at 246, South and Central America at 51, Africa at 88, and Europe (including Russia) at 60. LNG can supply the need while still emitting fewer GHGs compared to other fossil fuel alternatives
- Increasing the supply of natural gas through LNG is expected to place downward pressure on prices in the longer term. Much of the incremental production in North American basins is from unconventional sources such as shale formations, tight sands, and coal bed methane. These resources are generally more costly and energy intensive to develop due the need for advanced drilling techniques, such as horizontal drilling, and are also often characterized by smaller concentrations and steeper decline rates. Over the long-term, delivered LNG prices are expected to fall below the costs of incremental North American production, thereby moderating long-term natural gas prices.

- Significant investment in LNG in recent years contributes to increased supply and capacity as larger ships are used to haul LNG, the pipeline infrastructure is updated and expanded, and new technologies are developed that are potentially more efficient, cost-effective, and cleaner (emit fewer emissions).
- The significant number of geological structures in the US that are conducive to storage of natural gas will allow the U.S. to attract volumes of LNG during periods of oversupply to ensure reliable supply and mitigate commodity price volatility.

Comparison of Existing Coal Technology to Advanced Coal Technologies

Existing coal technologies emit approximately 50% more emissions than advanced coal technologies, IGCC and advanced ultra SCPC, through the combustion stage in the life cycle only, assuming all other life cycle stages are held constant. Due to environmental concerns, permitting and siting of new traditional coal-fired power plants has become increasingly difficult and IGCC and advanced ultra SCPC plants are not yet currently commercially viable in the U.S. Thus, in the near term, and considering the current situation of carbon regulatory uncertainty, it is not clear how much new coal capacity will be permitted, placing incremental supply pressures on gas – sourced either of domestically or internationally.

Comparison of LNG to Existing Coal Technology

The base case LCA results highlight some important differences between LNG and existing coal technologies, including:

- The overall difference between LNG and existing coal technology emissions was found to be 1,687 lbs CO_2e/MWh; or existing coal produces 161% greater emissions on a life cycle basis than that of LNG.
- The analysis indicated that the cleanest coal scenario (IGCC) releases 73% more emissions from a life cycle perspective than LNG.
- The LNG scenario emissions from processing and transportation segments were found to be greater than coal cases, largely due to the incremental processing steps (liquefaction and regasification) required for LNG and the resulting fugitive methane emissions' greater GHG potency (21 times that of carbon dioxide).

APPENDIX A: CONVERSION FACTORS AND EMISSION FACTORS

Description	Value	Unit	Source
kWh to Btu	3,412	Btu / kWh	TCR
kg to lb	2.205	lb / kg	TCR
g to kg	0.001	kg / g	TCR
barrel to gallon	42	gallons / barrel	TCR
short ton to lb	2,000	lb / short ton	TCR
MMBtu/Btu	1,000,000	Btu / MMBtu	TCR
MWh to KWh	1,000	kWh / MWh	TCR
g-C equiv/MJ to lbs CO2e/MMBtu	8.528	MMBtu –g-C / MJ-lb	Unit Analysis
Days to Hours	24	hour / day	
Years to Days	365	day / year	
Tonne LNG to MMBtu	51.1	MMBtu / Tonne LNG	Pace
Emissions Factors			
US Grid Electric Emissions Factor	1,369	lbs CO2e / MWh	EPA EGRID
Diesel Emissions Factors	73.15	kg CO2 / MMBtu	TCR
Diesel Emissions Factors	3	g CH4 / MMBtu	TCR
Diesel Emissions Factors	0.6	g N2O / MMBtu	TCR
Diesel Heat Content	5.825	MMBtu / barrel	TCR
Global Warming Potentials			
CO2	1	lbs CO2e / lb CO2	1995 IPCC SAR / TCR
CH4	21	lbs CO2e / lb CH4	1995 IPCC SAR / TCR
N2O	310	lbs CO2e / lb N2O	1995 IPCC SAR / TCR

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